BEFORE THE ARIZONA CORPORATION COMMISSION

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| IN THE MATTER OF POSSIBLE MODIFICATIONS TO THE ARIZONA CORPORATION COMMISSION'S ENERGY RULES | Docket No. RU-00000A-18-0284<br><br>Independent Analysis of the Energy System and Ratepayer Impacts of the Arizona Corporation Commission's Energy Rules |

## Independent Analysis of the Energy System and Ratepayer Impacts of the Arizona Corporation Commission's Energy Rules

The Southwest Energy Efficiency Project (SWEEP) is pleased to provide the attached report that provides an independent analysis of the energy system and ratepayer impacts of the Commission's Energy Rules.

The analysis was conducted by Strategen Consulting, a leading energy modeling and research firm with extensive national experience working with Fortune 500 corporations, state governments, and utilities.

To conduct the analysis, Strategen built a capacity expansion model of the Arizona power system and determined the state's cheapest, most reliable mix of energy options moving forward. The results of this least cost analysis were then compared with the Energy Rules's requirements (as approved in November 2020).

The model employed data from Arizona Public Service Company and Tucson Electric Power. The methodology is detailed in Chapter 3 of the report.

**The key findings of the analysis include the following:**

- The analysis identified the optimal, least-cost electricity generation resource portfolio from 2021 through 2035 for APS and TEP.
- This "Optimal Resource Portfolio" is characterized by:
  - A significant expansion of solar and battery storage totaling ~6,000 MW each,
  - Robust continued investment in energy efficiency, with cumulative savings equivalent to ~15% of retail sales over the next 10 years,
  - Maintenance of zero carbon electricity from the Palo Verde Nuclear Generating Station,
  - Integration of high-quality wind resources from New Mexico (over 1,000 MW),
  - A modest decline in natural gas generation from existing resources, and
  - Retirement of all uneconomic coal resources as early as is practicable.

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- The Optimal Resource Portfolio meets and even surpasses the Energy Rules' provisions for energy efficiency, energy storage, and carbon emissions through 2035.

- When compared to a Reference Case that approximates "business as usual," the Optimal Resource Portfolio reduces total electricity system generation costs by more than $2 billion (net present value) through 2035. This amount represents an 11% reduction in generation costs relative to the Reference Case, thereby yielding significant corresponding benefits to APS and TEP customers.

**In sum, the results of this analysis speak for themselves: Capitalizing on Arizona's untapped clean energy potential would deliver billions in savings for all Arizonans. Arizona simply cannot afford to delay. The Arizona Corporation Commission must act expeditiously to finalize and implement the Energy Rules to ensure reliable, least cost power for all Arizona ratepayers.**

**Finalization and implementation of the Energy Rules would also build on the significant success of the Commission's Electric Energy Efficiency Standard adopted in 2010.**

A summary of the ratepayer benefits of the Electric Energy Efficiency Standard's implementation from 2010-2019, as reported by TEP, APS, and UNS Electric in their annual demand-side management reports filed with the Commission, include the following:

- From 2010-2019, the efficiency programs of TEP, APS, and UNS Electric delivered more than $1.4 billion in ***net*** economic benefits to all Arizonans.[1]

- Efficiency has created more than 40,000 jobs across our state, including more than 28,000 jobs in Phoenix and 6,000 jobs in Tucson.[2] These jobs pay well, are local, and are in hands-on fields like installation so they cannot be easily outsourced.

- Together, APS and TEP's efficiency programs have saved more than 15,000,000,000 gallons of water.

- From 2010-2019, APS's efficiency programs alone avoided more than 1,000 MWs which is equivalent to avoiding the construction of 10 combustion turbine units at Ocotillo.

- From 2010-2019, every $1.00 of ratepayer money invested in APS and TEP efficiency programs returned ~$3.92 in total benefits to ratepayers.

Sincerely,

***Ellen Zuckerman***
Director, Utility Program, SWEEP

***Caryn Potter,***
Manager, Utility Program, SWEEP

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[1] 2010-2019 Annual Demand Side Management reports of TEP, UNSE, and APS filed with the Arizona Corporation Commission.

[2] Environmental Entrepreneurs, Energy Efficiency Jobs in America: Arizona: https://www.e2.org/wp-content/uploads/2018/09/ARIZONA-Dist.pdf

# AZ ENERGY RULES ANALYSIS

STRATEGEN

PREPARED FOR THE SOUTHWEST ENERGY EFFICIENCY PROJECT
JANUARY 21, 2021

YOUR PARTNER IN THE ENERGY TRANSITION

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# 1. Introduction & Background

## 1.1. Introduction

This technical research report is provided by Strategen Consulting on behalf of the Southwest Energy Efficiency Project.[1]

Strategen is a professional services company that specializes in power sector modeling and utility regulatory analysis. The firm has extensive experience working with global Fortune 500 corporations, utilities, governments, project developers, non-governmental organizations, and associations seeking to evaluate next generation grid and clean energy technologies.[2]

In November 2020, utility regulators at the Arizona Corporation Commission ("ACC") voted to initiate a formal rulemaking to update the state's "Energy Rules" to include, among other provisions, a requirement for the state's investor-owned electric utilities to be 100% carbon-free by 2050.[3] Should the Energy Rules be finalized and implemented, the state's two largest investor-owned electric utilities — Tucson Electric Power (TEP) and Arizona Public Service Company (APS) — would be subject to their requirements.

To examine the potential impact of the Energy Rules on Arizona's electricity system and its impact on electricity customers, Strategen's analytical approach and resulting recommendations were informed by two main research questions:

1. Would the implementation of the Commission's Energy Rules cause TEP and APS to deviate from a least-cost resource portfolio, thereby increasing costs for Arizona electricity customers relative to business as usual? And,
2. Would the implementation of the Commission's Energy Rules cause TEP and APS to compromise their primary resource planning objectives of affordability, reliability, risk mitigation, and environmental performance? If yes, what are the trade-offs between these objectives and reduced emissions?

To answer these questions, we utilized an advanced grid modeling software platform to identify the least cost generation resource portfolio in order to:

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[1] The Southwest Energy Efficiency Project (SWEEP) is a public-interest organization working to save money and protect the environment for the people and businesses of Arizona, Colorado, Nevada, New Mexico, Utah, and Wyoming through support of programs and policies that eliminate energy waste. For more information visit www.swenergy.org.

[2] For more information visit www.www.strategen.com.

[3] See ACC Decision No. 77829 dated November 23, 2020, https://docket.images.azcc.gov/0000202570.pdf?i=1610928380803

1. Reliably meet TEP's and APS's forecasted load growth;
2. Explore the impacts that the Energy Rules would have on Arizona's electricity system and electricity customers.

The precise methodology, including information on the EnCompass modeling software tool that was utilized, is detailed in the Technical Appendix of this report.

As discussed further herein, the answer to both research questions is: No. **Implementation of the Energy Rules would not impose any additional costs on Arizona electricity customers.** On the contrary, the Energy Rules could help ensure that TEP and APS pursue resource portfolios that are aligned with the most economically beneficial option for Arizona electricity customers — all without compromising reliability. These findings support the finalization and implementation of the ACC's Energy Rules. More detailed and sustained planning efforts will be needed over the next decade to ensure implementation is successful, but this high-level analysis suggests that there are no major barriers to the proposed Energy Rules.

## 1.2. Overview of Energy Rules Package

In November 2020, utility regulators at the ACC voted to initiate a formal rulemaking to update the state's Energy Rules. The Rules were developed after years of study, more than a dozen public meetings and workshops, thousands of written comments,[4] and hundreds of hours of engagement by stakeholders.

Among other provisions, the Energy Rules include:

1. A carbon-free electricity standard requiring affected utilities to achieve 100% carbon-free electricity by 2050 and meet benchmarks along the way, including 50% carbon emission reductions by 2032 and 75% carbon emission reductions by 2040, relative to a 2016 to 2018 baseline.
2. An energy efficiency standard requiring affected utilities to save at least 1.3% annual energy savings through 2030 (averaged over three-year periods) and to deliver demand side resources equivalent to a 35% reduction in the utility's 2020 peak demand by 2030.
3. A 5% by 2035 energy storage requirement for which 40% must come from customer-owned or customer-leased systems.
4. Integrated resource planning process changes to enhance stakeholder engagement opportunities (including the creation of a stakeholder committee that is empowered to review utility load forecasts, Request for Proposal (RFP) language, and developed portfolios) and requirements for utilities to issue competitive all-source RFPs.

[4] Appendix B: Index of Written and Oral Comments in Support of the Energy Rules, Joint Stakeholder Comments in Support of the Commission's Energy Rules, January 20th, 2021, https://docket.images.azcc.gov/E000011269.pdf?i=1611209505495

Additional details on each of these provisions are provided below.

As part of its formal rulemaking, the Commission scheduled oral public comment sessions on January 19 and 20, 2021, and is accepting written comments through January 22, 2021.[5] At the conclusion of the formal rulemaking, Arizona Corporation Commissioners will cast a final vote to adopt the Rules. If affirmative, the Rules will be transmitted to the Arizona Attorney General's office for review.

### 1.2.1. Carbon-Free Electricity Standard

Under the Commission's Energy Rules approved in November 2020, an affected electric utility must achieve a 100% reduction in carbon emissions by 2050 and meet requirements along the way, including 50% carbon emission reductions by 2032 and 75% and 75% carbon emission reductions by 2040 — all relative to a 2016 to 2018 baseline. This baseline is defined as the average annual metric tons of carbon emissions from all generating units used to meet the utility's retail kWh sales during the consecutive three-calendar-year period of 2016 to 2018.

Figure 1 below from TEP's 2020 Integrated Resource Plan, which depicts the utility's historical and future carbon emissions under multiple scenarios, shows that its 2016-2018 carbon emissions were around 10 million metric tons (or 11 million short tons).

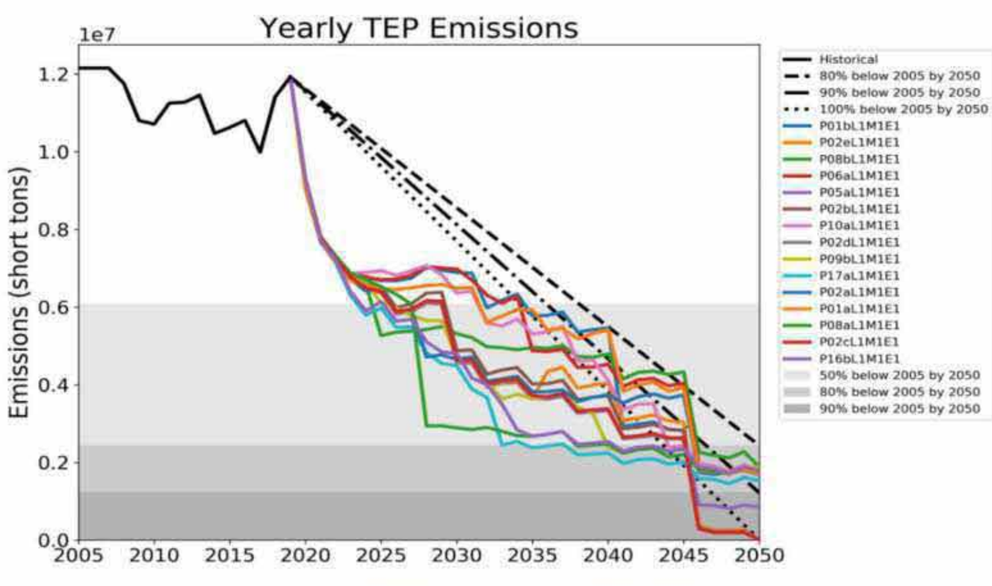


*Figure 1: TEP Carbon Emissions (2005-2050)*

A similar graph from APS's 2020 Integrated Resource Plan shows that its 2016-2018 carbon emissions were around 11 million metric tons.

[5] See ACC Docket No. RU-00000A-18-0284

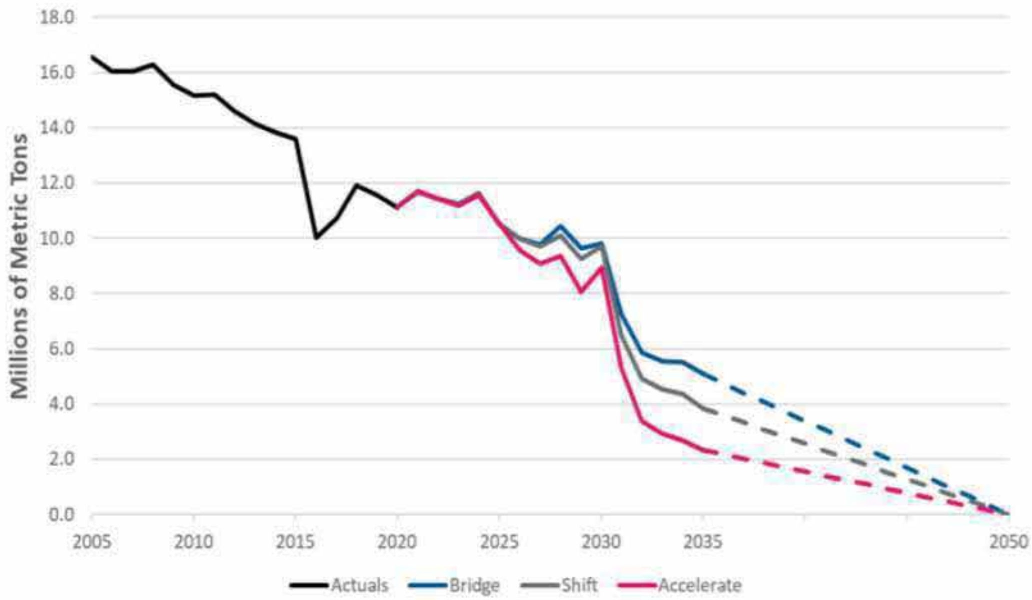


*Figure 2: APS Carbon Emissions (2005-2050)*

### 1.2.2. Energy Efficiency

The Energy Rules require an affected utility to deliver demand side resources equivalent to a 35% reduction in the utility's 2020 peak demand by 2030. Additionally, an affected utility's Energy Implementation Plan must also deliver at least 1.3% annual energy savings through 2030 (averaged over three-year periods) through new demand side management programs that include traditional energy efficiency, demand response, and other programs that focus on reducing overall energy usage, peak demand management, and load shifting.

### 1.2.3. Energy Storage

The Energy Rules require an affected utility to install energy storage systems with an aggregate capacity equal to at least 5% of the electric utility's 2020 peak demand by 2035. Forty percent of this requirement must be derived from customer-owned or customer-leased distributed storage systems.

### 1.2.4. Integrated Resource Planning Reforms

The Energy Rules include changes to the Commission's integrated resource planning process to enhance stakeholder engagement opportunities (including the creation of a stakeholder committee that is empowered to review utility load forecasts, Request for Proposal (RFP) language, and developed portfolios) and requirements for utilities to issue all-source RFPs over three-year periods through 2030. Additionally, the Energy Rules include provisions for Commission approval of a specific portfolio of resources and for the preferential siting of renewable resources on Tribal lands or in communities impacted by the early closure of conventional power plants.

# 2. Key Findings

The key findings of Strategen's analysis in this study can be summarized as follows:

- Our analysis identified the optimal, least-cost electricity generation resource portfolio from 2021 through 2035 for APS and TEP.
- This "Optimal Resource Portfolio" is characterized by:
  - a significant expansion of solar and battery storage totaling ~6,000 MW each,
  - robust continued investment in energy efficiency, with cumulative savings equivalent to ~15% of retail sales over the next 10 years,
  - maintenance of zero carbon electricity from the Palo Verde Nuclear Generating Station,
  - integration of high-quality wind resources from New Mexico (over 1,000 MW),
  - a modest decline in natural gas generation from existing resources, and
  - retirement of all uneconomic coal resources as early as is practicable.
- The Optimal Resource Portfolio meets and even surpasses the Energy Rules' provisions for energy efficiency, energy storage, and carbon emissions through 2035.
- When compared to a Reference Case that approximates "business as usual," the Optimal Resource Portfolio reduces total electricity system generation costs by more than $2 billion (net present value) through 2035. This amount represents an 11% reduction in generation costs relative to the Reference Case, thereby yielding significant corresponding benefits to APS and TEP customers.

## 2.1. Optimal Resource Portfolio

Our analysis modeled the least-cost portfolio of energy resources through 2035 for the electricity systems of APS and TEP. The model did not explicitly include constraints for the Energy Rules' provisions, but rather aimed to investigate whether the relevant targets under the Energy Rules would be achieved under a cost optimized approach.

The analysis included most of the inputs and assumptions included in the 2020 Integrated Resource Plans of TEP and APS, with some specific adjustments. Those adjustments aim to ensure that the data driving resource portfolio selection accurately represent the most up-to-date information on energy costs. They also aim remove any artificial operational constraints that significantly limit the utilities' flexibility in achieving a least cost portfolio (e.g., removing must-run constraints for coal units). The precise methodology and adjustments are detailed in the Technical Appendix of this report.

The resource mix that meets both utilities' forecasted demand for energy and capacity while resulting in the lowest cost for their customers is depicted in the graph below. The graph includes generation from utility-owned resources or power purchase agreements, whether serving local load or exported. Short-term market purchases from Palo Verde are not depicted, but also contribute to the energy mix and fluctuate from about 0 to 5,000 GWh depending on the year.

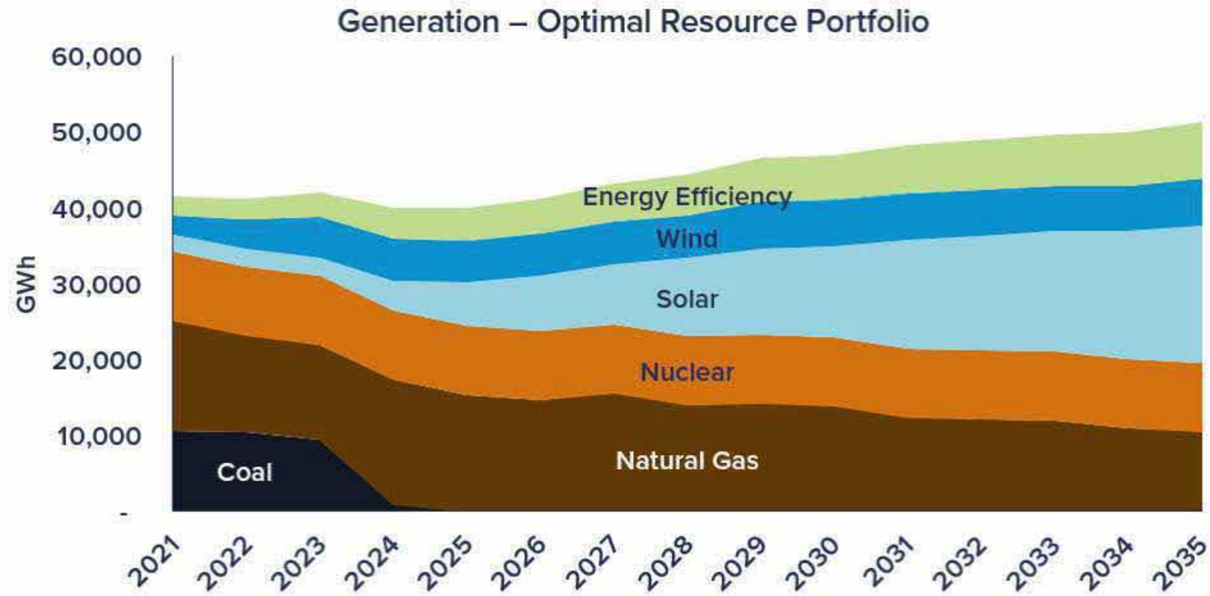


*Figure 3: Energy Generation (GWh) of the Optimal Resource Portfolio*

Since Arizona is one of the sunniest states and has enormous solar potential, the model unsurprisingly adds significant amounts of solar and solar + storage resources, as well as standalone battery storage to provide additional firm capacity. Together these solar and storage resource additions represent over $10.5 billion of investment in Arizona's energy economy. Furthermore, wind is added in early years to take advantage of the Production Tax Credit (PTC), which was just extended in the 2020 federal stimulus package. New Mexico's high-quality wind resources can result in higher capacity factors, and thus the added wind is primarily imported from there. Coal operations are reduced to extremely low levels, as the units are generally already uneconomic (i.e., "out of the money"). A large portion of the coal-fired capacity is retired in the 2024 timeframe, which is the earliest year that the model allows such retirements to occur. Retirements in 2021 - 2023, even if economic, are not allowed in the model in order to reflect the practical realities of closing large generation facilities as well as the need to plan for a just and equitable transition to a cleaner grid. See tables below.

| Generation & Demand Resources (MW, nameplate) | Current Portfolio (2021)[6] | 2035 Optimal Resource Portfolio |
|---|---|---|
| Solar | 826 | 6,697 |
| Wind | 861 | 1,948 |
| Battery Storage | 25 | 5,830 |
| Other Renewables | 30 | 20 |
| Natural Gas | 5,964 | 4,729 |
| Coal | 2,314 | 0 |
| Nuclear | 1,146 | 1,146 |
| Energy Efficiency[7] & Demand Response | 0 | 3,830 |
| **Total** | **12,195** | **24,199** |

| Energy Mix (GWh) | Current Portfolio (2021) | 2035 Optimal Resource Portfolio |
|---|---|---|
| Solar | 2,240 | 18,018 |
| Wind | 2,596 | 6,265 |
| Other Renewables | 11 | 91 |
| Natural Gas | 14,445 | 10,509 |
| Coal | 10,662 | 0 |
| Nuclear | 9,111 | 9,128 |
| Energy Efficiency & Demand Response | 0 | 7,296* |
| **Total** | **41,593** | **51,308** |

* By 2030, the Optimal Resource Portfolio results in 6,164 GWh of cumulative energy efficiency resources. The Energy Rules' energy efficiency requirement is through 2030 and not 2035 (which the table above displays).

## 2.2. Arizona Energy Rules through 2035

The resulting least-cost portfolio identified in this analysis not only satisfies all of the Energy Rules provisions but far exceeds them in certain cases (e.g., for energy storage and carbon emissions reductions). Specifically, when examining both utilities combined, the Optimal Resource Portfolio results in:

- A 73% reduction in carbon emissions by 2032 relative to the 2016-2018 baseline. Emissions are reduced 83% for TEP and 64% for APS. Given the recent or planned

[6] Includes some planned new additions with expected commercial operation dates in 2021.
[7] Excludes historical EE savings.

retirement dates of the Cholla, Four Corners, Navajo, San Juan, and Springerville[8] coal-fired power plants – all of which are included in the baseline and will retire by 2031 or sooner – the 50% reduction of carbon emissions targeted by the Energy Rules is readily achievable even under "business as usual" conditions. **The model results from this analysis show that accelerating these emissions reductions to a date prior to 2032 is not only achievable but is also part of the least cost portfolio for Arizona.** Economic cycling and economic retirement of the coal units prior to the announced dates could result in significantly lower cumulative emissions, which is a more important metric from a climate change mitigation standpoint versus the annual emissions reduction contemplated by the Energy Rules.

- 5,830 MW of energy storage (nameplate) by 2035, which equals over 57% of the 2020 peak load of TEP and APS. Although the model does not differentiate between centralized and distributed resources, the overall magnitude of storage deployed under the Optimal Resource Portfolio suggests that even a small fraction of the 5,830 MW total could fulfill the Energy Rules' overall requirement for customer-owned storage resources (i.e., 40% of the 5% storage requirement). More specifically, the customer-owned requirement amounts to approximately 200 MW, or about 3-4% of the total storage deployed under the Optimal Resource Portfolio.

- 6,164 GWh of cumulative energy efficiency savings through 2030.[9] This equates to cumulative savings from 2021-2030 equal to approximately 15% of retail sales in 2030, or about 1.5% per year. This exceeds the required annual savings amount under the Energy Rules of 1.3% per year through 2030. Additionally, the new energy efficiency measures selected comprise demand side resource capacity of approximately 3,000 MW by 2030, or about 30% of total peak demand in 2020. When combined with well over 1,000 MW of historical energy efficiency from APS alone plus other demand-side resources (e.g. distributed generation, distributed storage) the portfolio will easily surpass the 35% of the utilities' 2020 peak demand as required by the Energy Rules. This is before including any contribution from rates or incremental demand response that may also be eligible to count toward this target.

[8] Units 1 & 2 owned by TEP
[9] Reflects savings at the generator after EE savings are grossed up for losses assuming a 7% loss factor.

| Component | Energy Rules Requirement | Optimal Resource Portfolio Results |
|---|---|---|
| Energy Efficiency (2030) | 1.3% annual average savings over 10 years (as % of sales, averaged over three-year periods), or ~13% by 2030 | 1.5% annual average savings over 10 years (as % of sales), or ~15% by 2030; (6,164 GWh cumulative savings) |
| Peak Demand Reduction from Demand Side Resources (2035) | Demand side resource capacity equal to 35% of 2020 peak demand, by 2030 | >40% of 2020 peak demand from energy efficiency by 2030 (includes historical savings; does not include other demand-side resources that may contribute) |
| Energy Storage (2035) | 5% of 2020 peak demand | ~57% of 2020 peak demand (5,830 MW by 2035) |
| Carbon Emissions (2032) | 50% reduction from baseline, (decrease from ~21 M tons/year to ~10.5 M tons/year) | 73% reduction from baseline, (decrease from ~21 M tons/year to ~5.4 M tons/year) |

These results indicate that the implementation of the Energy Rules should not impose additional generation costs on TEP, APS, and their customers if the Optimal Resource Portfolio is pursued. In the event that an economically suboptimal portfolio is pursued, the Energy Rules may in fact provide a safeguard to ensure cost savings for utility customers are achieved.

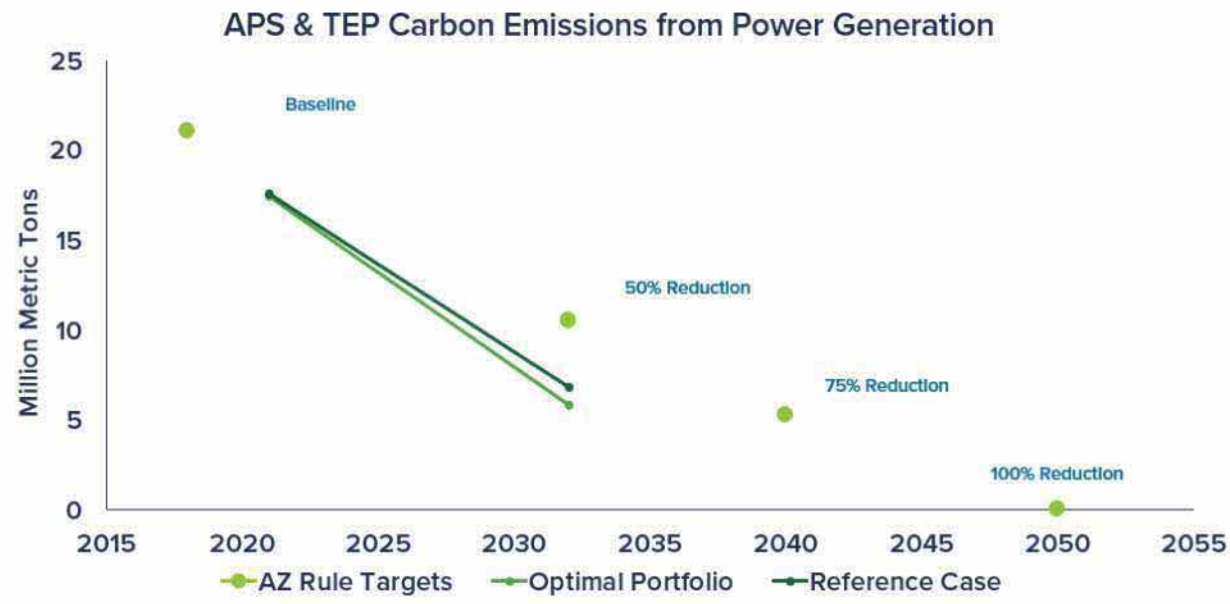


*Figure 4: Emissions trajectory through 2032 for the Optimal Portfolio and Reference Case compared to the Energy Rules*

## 2.3. Costs to Electricity System Customers

As part of its analysis, Strategen assessed the total going-forward costs of the TEP and APS generation portfolios, including the costs of new capital investments and ongoing operating costs, which are ultimately paid by each utilities' customers. This analysis reflects a core part of the optimization routine conducted by the EnCompass modeling software tool, which uses advanced linear programming techniques to minimize an objective function subject to constraints that reflect physical limitations of the power system. In each model run, the objective sought by EnCompass was to identify the resource portfolio that would minimize overall system costs with sufficient energy to meet the forecasted load and capacity to exceed the reserve planning margin. The capital expenditures and operating costs of these resources are part of the net present value of the utilities' annual revenue requirements.

When optimized for this lowest cost portfolio, Strategen found that the Optimal Resource Portfolio not only meets but exceeds the required provisions of the Energy Rules. As such, utility customers as a whole would incur no additional costs from the adoption and implementation of the Energy Rules. In fact, in several cases it appears that going beyond the minimum requirements of the Energy Rules would actually benefit utility customers. For comparison purposes, we sought to evaluate the Optimal Resource Portfolio – which also happens to meet the requirements of the Energy Rules – against a "business as usual" or "Reference Case" that does not pursue the level of carbon emissions reductions or energy efficiency measures that are associated with the Optimal Resource Portfolio. While it is by no means identical, this Reference Case more closely resembles the current plans of the investor-owned utilities as detailed in their 2020 integrated resource plans, which include substantially lower levels of carbon emissions reductions prior to 2032 (due to continued coal operations) and lower levels of energy efficiency. The table below shows the net present value (NPV) revenue requirements of the Reference Case versus the Optimal Resource Portfolio, illustrating that the Optimal Resource Portfolio yields about $2 billion (NPV) in cost savings for Arizona electricity customers.

| Revenue Requirement, NPV 2021-2035 ($ billions)[10] | Reference Case | Optimal Resource Portfolio | Change |
|---|---|---|---|
| APS | $ 13.8 | $ 12.4 | $ (1.4) |
| TEP | $ 5.0 | $ 4.4 | $ (0.6) |
| TOTAL | $ 18.8 | $ 16.8 | $ (2.0) |

[10] Note that the revenue requirement totals displayed represent the going-forward generation capital and operating costs only and exclude certain items such as depreciation on existing plants, distribution costs, etc., that are not expected to vary across between scenarios. As such, these absolute values are not comparable to revenue requirement values used in the APS and TEP IRPs.

Notably, the selection of 2032 as the date for the 50% carbon emissions target, and the 2016-2018 baseline, mean that the Energy Rules are unlikely to require any acceleration in the retirement of uneconomic coal plants — a large source of potential customer benefits — beyond what is already planned. Both TEP and APS have already announced plans to exit key coal facilities in the 2031-2032 timeframe. However, to the extent the carbon-free electricity standard encourages closer examination of these announced retirement dates, and in turn encourages further acceleration of announced retirements, then additional customer benefits could be realized, both economic and environmental. At the very least, the Energy Rules would provide a safeguard by guaranteeing that customers are not paying for uneconomic coal beyond 2032.

It is worth noting that savings from uneconomic coal plant retirements drive a substantial portion of the customer benefits of the Optimal Resource Portfolio relative to the Reference Case. These savings have also been examined to consider the fact that existing coal supply agreements may have either take or pay provisions or termination fees associated with them. These have been evaluated in post-analysis and found not to substantially alter this study's conclusions.

Furthermore, the Energy Rules appear to drive some amount of incremental energy efficiency savings beyond what had been planned. This also helps to drive down the revenue requirement and resulting customer bills in the Optimal Resource Portfolio.

Regarding energy storage, the Optimal Resource Portfolio includes a significant amount of new battery storage, well above the Energy Rules' 5% by 2035 requirement. However, one limitation in this study's analytical approach was that the model was not explicitly configured to differentiate between the utility-owned portion and the Rules' required 40% customer-owned portion. As such, we conducted a post analysis to evaluate the impact this provision could have on overall system costs. Based on peak load projections, we estimate the customer-owned storage requirement to be about 200 MW by 2035. Generally speaking, smaller scale storage systems that could be sited at a utility customer's location have higher per unit costs. Thus, the inclusion of the 40% customer-owned requirement could lead to an increase in the total cost of deploying storage resources. For example, according to one recent industry forecast, the levelized cost of large-scale battery storage systems (4 hour duration) commencing operation in the near-term was estimated to be $183-340/kW-year compared with a smaller scale commercial and industrial (C&I) customer deployment which would be $392-507/kW-year.[11] This would equate to about a 50% to 100% increase in capital costs for this small portion of the total storage resources deployed to meet the customer-owned storage requirement. However, a significant portion of these incremental costs are likely to be borne by the customers owning the storage systems themselves and would not

[11] Based on Lazard's Levelized Cost of Storage 2020.

directly increase the utilities' revenue requirement. Some indirect costs may be incurred through utility rates and programs designed to support these customer-owned deployments. Assuming this indirect support equates to about 50% of the total customer-owned storage investment costs, then the net effect would be a \$0 to \$105/kW-yr increase in incremental utility system costs for these customer-owned storage resources. We estimate this would equate to about \$0-21 million, or about a 0-1% increase in the 2035 annual revenue requirement for generation.

## 2.4. Beyond 2035

The modeling conducted for this analysis built upon previous analyses conducted by Strategen on the APS and TEP 2020 Integrated Resource Plans, which use a 2035 planning horizon. As such, the primary focus of the analysis conducted was through 2035. However, we are cognizant that the Energy Rules' carbon-free electricity standard extends to 2050. To test the feasibility of reaching zero emissions by 2050, we explored a High Emissions Reduction case, that would achieve 90% emissions reductions by 2035. In Strategen's view this would provide ample time to achieve the final 10% of reductions by 2050, as required by the Energy Rules, and also allow this to be achieved at a reasonable cost since the costs would be spread over 15 years (i.e., the time between 2035 and 2050).

To achieve deep decarbonization at a reasonable cost, the system could benefit from the addition of a dispatchable clean energy resource, such as geothermal, longer-duration batteries (or other type of long duration storage), green hydrogen, or some other emerging technology. Although the exact attributes of certain emerging technologies cannot be precisely modeled, the pace of technological advancement for generation technologies over the past years indicates that such a resource will be available and economic. Moreover, resources like geothermal are already commercialized and could be used to meet this need. To model this resource, we have included a proxy resource option that is intended to reflect either a generation unit running on green hydrogen or a geothermal resource. A detailed description of this resource and its characteristics is included in the Technical Appendix of this report.

In the High Emissions Reduction Portfolio, this generic firm clean energy resource is needed and deployed in later years (i.e., 2030 and beyond). Natural gas generation is gradually reduced and is the only source of the remaining 10% of emissions in 2035. Energy Efficiency and renewable resources grow at a similar pace as in the Optimal Resource Portfolio, but the firm clean energy resource is the one that helps the system reach the level of deep decarbonization in later years. The additional emissions reduction to reach 90% is achievable at a higher cost for electricity customers compared to the Optimal Resource Portfolio presented above. However, this cost still appears to be reasonable. Specifically, an incremental cost of \$320 million in the NPV of the revenue requirement results in carbon emissions reductions of 9 million tons over the 15-year period. Thus, the mitigation cost for each additional ton of carbon emissions avoided in the 90% reduction by 2035 case is equivalent to $36/ton. Despite the slightly higher NPV of the revenue requirement compared to the Optimal Resource Portfolio, the revenue requirement remains significantly lower than the Reference Case in which coal units continue to operate up to 2032 and lower energy efficiency levels are pursued. Specifically, the 90% reduction in carbon emissions compared to the utilities' baseline level still results in $1.7 billion of savings and a reduction of 62 million tons of carbon emissions over the 15-year period.

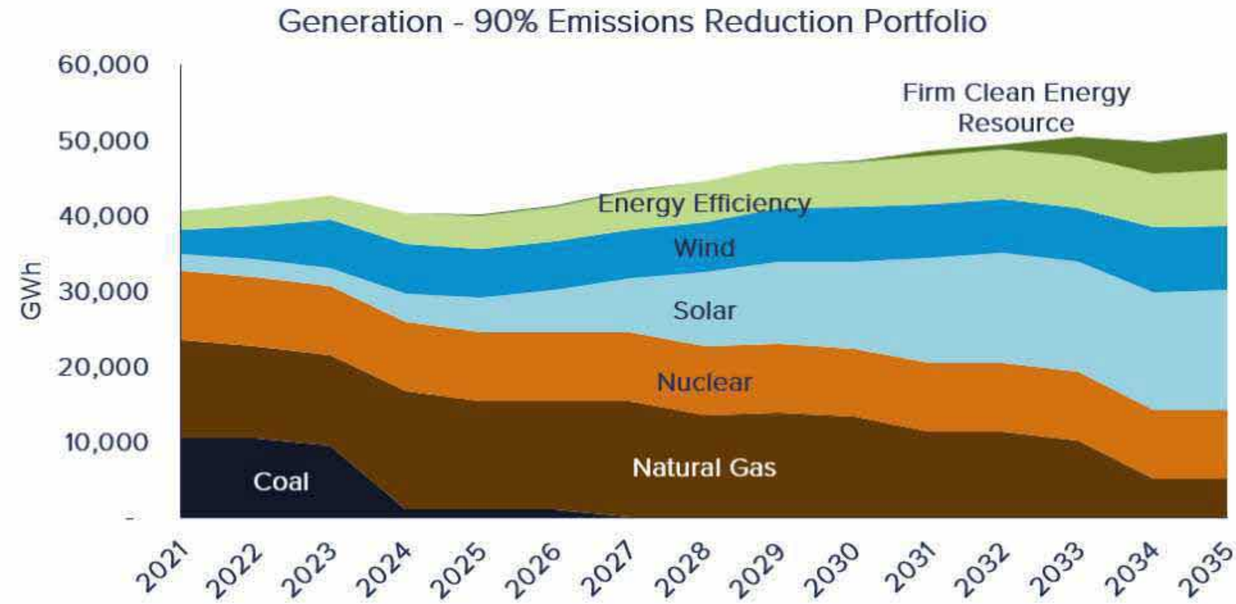


*Figure 5: Energy Generation (GWh) of the Resource Portfolio achieving 90% emissions reduction by 2035*

## 2.5. Conclusion

If Arizona's investor-owned utilities were to pursue an optimal generation portfolio consistent with this analysis, then the requirements imposed by the Energy Rules would not only be feasible through the 2035 timeframe, but would be aligned with the least-cost portfolio. In other words, complying with the Energy Rules would bring no additional costs for electricity customers under an optimal planning scenario.

Beyond 2035, more analysis may be needed to understand the precise portfolio of resources necessary to meet the 100% zero emissions objective while minimizing costs. However, it is clear from this analysis that 90% emissions reductions is readily achievable on the 2035 timescale while still reducing customer costs versus a "business as usual" scenario. Over the following 15 years, renewable energy and storage technology costs are expected to continue declining, while new clean technologies that provide dispatchable energy will keep evolving. As such, options for additional emissions reductions beyond 90% appear to be readily achievable and should continue to be explored and analyzed in the coming months and years.

# Technical Appendix

## 1. Modeling Methodology

In conducting this analysis, Strategen used the EnCompass power planning software tool, developed by Anchor Power Solutions. EnCompass is commercially available and is accompanied by a dataset called the Horizons Energy database that provides information on the U.S. electricity grid. EnCompass can be configured either as a capacity expansion model or a production cost model.

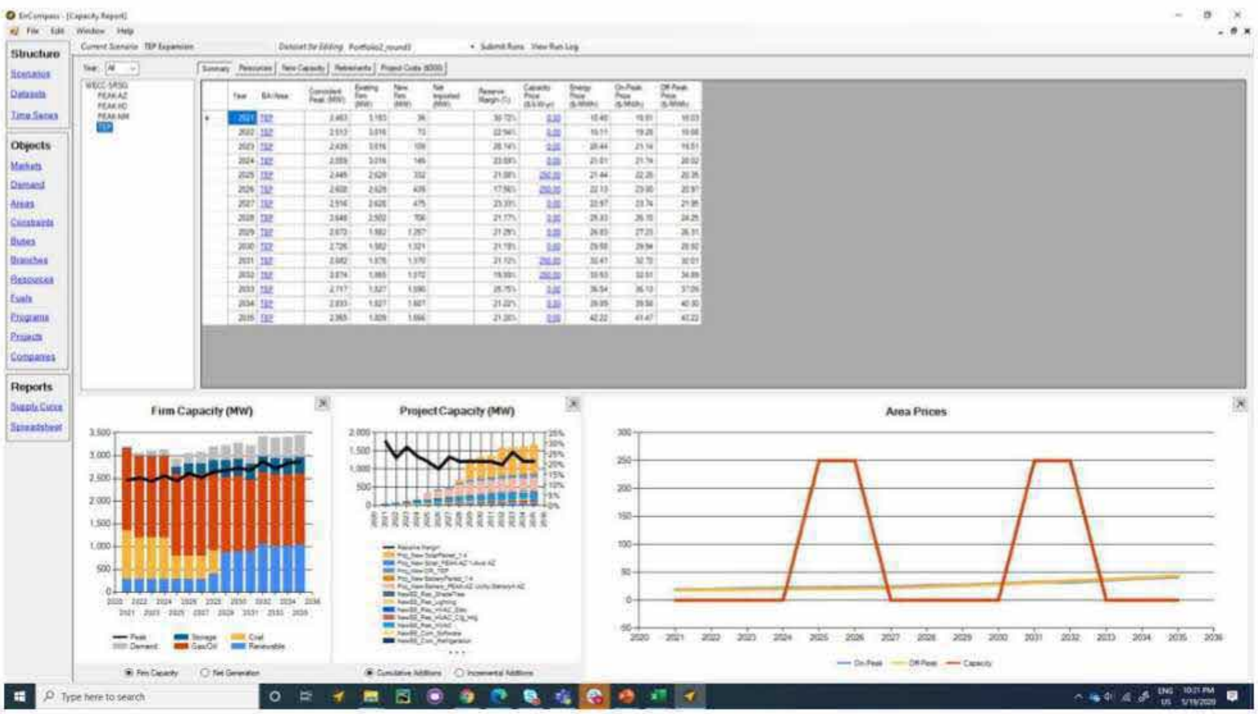


Figure 6: Snapshot of the EnCompass User Interface

A capacity expansion model finds the least cost resource portfolio that meets the projected electricity demand over a period of several years. A production cost model finds the least cost dispatch of a given or pre-determined system of generators. Capacity expansion models have been traditionally used to provide investment guidance, while production cost models have been employed to provide answers to short-term operational questions or to perform comparisons of pre-selected or pre-determined portfolios. A capacity expansion model selects the resources that can serve the forecasted load over a period of several years at minimum cost. It is, therefore, suitable for developing utility resource plans and assessing the costs and benefits of longer looking utility regulatory policies such as the ACC's Energy Rules.

Accordingly, for this study, EnCompass was run as a capacity expansion model with a planning horizon of 2035. In this mode the model determines not only the most economic way to utilize existing resources, but also which technologies should be added in the future, and which existing resources should be retired, while meeting the forecasted load and any policy goals outlined in each simulation.

The figure below shows the inputs and outputs of a capacity expansion model.

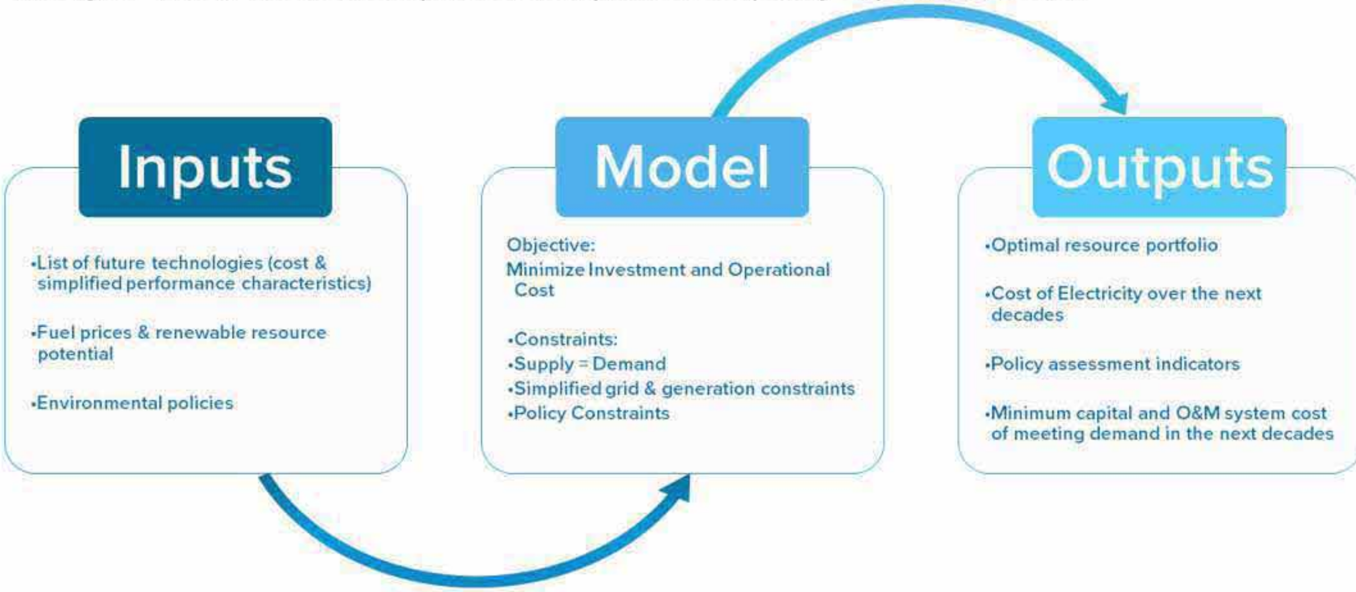


Figure 7: Capacity Expansion Model: inputs & Outputs

This analysis focuses on a scenario that does not include any constraints based on the Energy Rules, i.e., storage is not explicitly required to surpass 5% of the peak demand, etc. Instead, the model can select resources that most economically meet the forecasted load. The resulting portfolio is then analyzed to determine whether it meets the Energy Rules' provisions or not.

The model simulates the TEP and APS balancing areas; import capability from New Mexico, as a representation of potential wind resources; and import/export capability to the Palo Verde hub as a representation of the utilities' interconnection to other utilities in the state (including Salt River Project) and the broader region. A depiction of the model topology is shown below. Palo Verde hub prices were based on assumptions provided by APS.

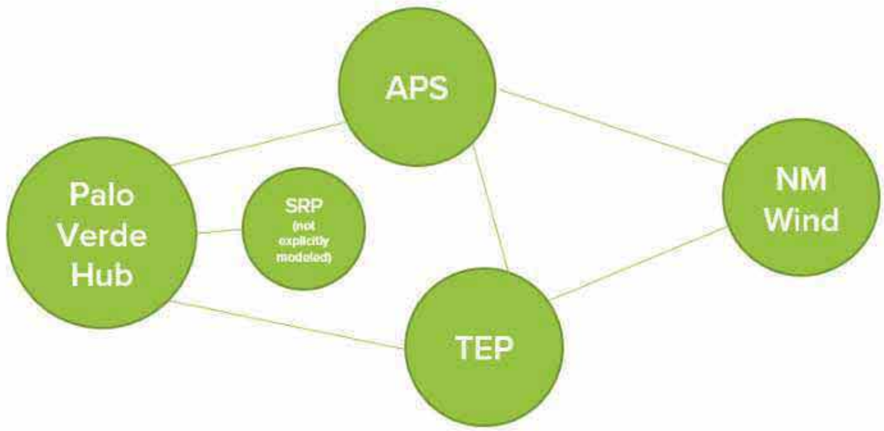


*Figure 8: Modeled Network in EnCompass*

## 2. Inputs & Assumptions

Horizons Energy provides a dataset that accompanies the EnCompass model and includes all of the units, resource characteristics, and grid details of the U.S. power system. The analysis uses the Arizona data from the Horizons Energy database as a starting point, and was further refined by TEP's and APS's 2020 Integrated Resource Plan assumptions, as well as adjustments based on recent policy developments, and the Strategen team's expert judgement.

### 2.1. Load Forecast

Forecasting load is a foundational component of a resource plan, fundamental to analyzing the number, timing, and type of resources a utility needs. The forecast is long-term in nature, with more emphasis placed on the near-term, as the near-term outlook guides short-term decision-making in a utility's three-to-five year "Action Plan" window, while the long-term forecast is important to develop a long-term strategy, directional resource targets, and assess policy impacts.

The present analysis uses the load forecast from the utilities' 2020 integrated resource plans filed with the ACC. Specifically, TEP's underlying sales forecast shows an expected annual growth rate of 0.8% in the 2020 to 2035 period. Incremental growth in electric vehicle use is expected to increase the annual growth rate to 1.3%, and the proposed Rosemont mine project would increase the annual growth rate to 1.7% starting in 2028.

APS' 2020 integrated resource plan considers a peak consumption hour growth rate under three scenarios – (1) a "Base Assumption" scenario with a 2.1% annual growth rate; (2) a scenario with a forecast growth rate of 0.9%, and (3) a scenario with no growth or 0%. Annual growth rates reflect peak load growth after customer resources (including energy efficiency and distributed energy are accounted for). For the purposes of this analysis, Strategen used the 0.9% growth scenario, which most closely matches recent trends.

Both utilities forecast their retail sales and wholesale obligations and then subtract the separately forecasted demand side resources. However, for the purposes of this analysis, Strategen modeled energy efficiency endogenously in the capacity expansion model, to provide a more accurate cost comparison of supply and demand side resources. Thus, the modeling exercise used a load forecast based on the utilities' integrated resources plans, but grossed up to include the energy efficiency component, such that it could be selected by the model as a resource in the optimal mix (rather than being embedded in the load forecast).

## 2.2. Resource Characteristics

Cost and performance characteristics including heat rates, minimum levels of operation, variable operations and maintenance (O&M) costs, fixed O&M, and incremental capital expenses were updated in the Horizons database based on the utilities' 2020 integrated resource plans.

## 2.3. Fuel & Power Prices

The analysis uses the annual fuel prices and hourly wholesale market prices for the Palo Verde node included in the APS 2020 integrated resource plan.

## 2.4. Carbon Price

Consistent with APS and TEP's standard planning practice, we included a future carbon price assumption in the model. The primary portfolio presented in the analysis includes a carbon price derived from APS' 2020 integrated resource plan which is depicted below.

Figure 9: Carbon Price in the APS and TEP IRPs

## 2.5. Federal Tax Credits for Renewable Energy

In December 2020, the U.S. Congress passed a spending bill that includes $35 billion in energy research and development programs, a two-year extension of the Investment Tax Credit (ITC) for solar power, a one-year extension of the Production Tax Credit (PTC) for wind power projects, and an extension through 2025 for offshore wind tax credits. The two-year extension of the federal ITC for solar projects will retain the current 26% credit for projects that begin construction through the end of 2022, rather than expiring at the end of 2020 as they would have under existing law. The ITC will fall to a 22% rate for projects that begin construction by the end of 2023, and then fall to 10% for large-scale solar projects and to 0% for small scale solar projects in 2024. Additionally, many of the large-scale solar development set to be completed through 2023 have used "safe-harbor" provisions to secure the original 30% ITC credit (as long as the project is completed within 4 years), thereby removing the risk of seeing project financing disrupted by a reduction in the tax credits. Similarly, many wind projects have used safe harbor to secure PTC credit at a higher level. Through "commence-construction" or "safe-harboring" provisions by 2023, solar ITC projects can secure the 26% and 22% credits in 2022 through 2025. Below is a table of the ITC that was modeled for solar PV and solar+storage projects that were commercially available by a certain date.

| Commercial Date of operation | ITC (%) |
|---|---|
| 1/1/2021-12/31/2022 | 30% |
| 1/1/2023-12/31/2023 | 26% |
| 1/1/2024-12/31/2024 | 22% |
| After 1/1/2025 | 10% |

Similarly, the one-year extension for the PTC combined with the safe harbor provisions are modeled as shown below:

| Commercial Date of Operation | PTC (%) |
|---|---|
| 1/1/2021-12/31/2021 | 80% |
| 1/1/2022-12/31/2023 | 60% |
| After 1/1/2024 | 0 |

## 2.6. Existing Coal Resources

TEP's and APS's supply resources include a significant percentage of coal-fired generation: Units 1 and 2 at the Springerville plant account for nearly 800 MW, while TEP's and APS's share of the Four Corners Power Plan account for over 1,000 MW.

### Coal Unit Operations

Traditionally, coal units have been considered a baseload resource and were designed to turn on and stay on, running all year round and meeting the portion of demand that appears constant in aggregate. Baseload resources have historically had high capital costs but low operating costs, and as such it was economic to run them most of the time, resulting in high capacity factors.

However, coal units are not baseload resources anymore. On the contrary, they now are some of the most expensive resources in an electric system due to the declining cost of alternative technologies including solar, wind, natural gas, and batteries. New patterns of net demand also mean they are not needed in every hour of the year. Unfortunately, in many regions, despite the clear change in system economics, the past practices of running coal units as baseload resources have not changed, resulting in uneconomic operations and higher costs to utility customers. While in real world operations, utilities can choose to operate their units regardless of economic considerations, within a mathematical model that is designed to choose the least cost resources (such as EnCompass), the continued operation of coal units can only be achieved by the introduction of artificial constraints dictating that those units should remain online despite their higher cost. These constraints are often called "must-run" constraints. The relaxation or elimination of such constraints both in the modeling, as well as in real life operations, is defined as "economic cycling."

Acknowledging that the utilities follow this common practice of including must run constraints in their modeling, we run EnCompass in a similar manner, requiring the continued operation of coal units, but also without this constraint. The relaxation of those constraints to allow for economic cycling throughout the year can lead to significant savings for electricity customers and emissions reductions. These savings are available immediately since coal-fired electricity is already significantly more expensive than currently available resources (even when accounting for construction costs of new resources). Certain conditions, like minimum tonnages in existing coal supply agreements might limit the savings for some of the units. However, before dismissing the idea of economic cycling or economic retirement, the utility should first investigate any provisions that could allow for an early termination of the contract or even the penalty associated with take-or-pay quantities that are not consumed. Those penalties should be compared against the forecasted O&M, capital, and fuel savings of economic operations and retirement and only then an optimal decision can be made.

TEP has already proposed seasonal cycling of one of the Springerville units starting in 2023, but further carbon and cost reductions could be achieved by an earlier introduction of seasonal (or full) economic cycling for both units.

### Coal Unit Retirement

In addition to cycling, the model also allows for economic retirement of the coal units. Again, historically, both in real world operations, as well as in modeling, units were retired only once they reached their economic book lifetime. However, the dramatic reductions in costs of renewable resources have challenged this practice. Coal units are becoming increasingly more expensive to operate and maintain in a system, introducing the concept of accelerated or economic retirement. The concept has started spreading worldwide as new capital investment in renewable resources, often paired with energy storage, can be much more cost competitive when compared to the operating expenses of keeping a coal unit in the system. This has led to decisions to retire fossil fuel plants based on economics even before their economic book life is reached.

Allowing economic retirement means that the model can not only select which units to invest into but can also retire a unit before its scheduled retirement date, if doing so would achieve cost savings for electricity customers. This decision is based on a forward-looking analysis, i.e., retirement decisions account for the avoidable costs should a unit retire early and is not limited by unavoidable costs associated with a unit's undepreciated balance of plant. Based on economic theory, undepreciated capital expenses are considered "sunk costs" and should not bear on decisions for which investments should be made.

If undepreciated balance of plant costs do exist, then it may be a policy matter for the ACC to decide whether, how, and when these "stranded costs" should be recovered if a plant is retired early. However, it is important to recognize that customers can benefit from economic retirements regardless of whether they pay these fixed costs ("stranded costs") following plant retirement. Keeping uneconomic units online solely to allow for full book life to be realized only results in higher costs for utility customers due to the ongoing operating costs incurred.

## 2.7. Energy Efficiency

As part of the integrated resource planning process each utility has projected energy savings from implementing energy efficiency measures over the next 15 years. This forecast is not usually part of the capacity expansion model and is instead based on separate studies conducted prior to the selection of the rest of the supply resources. However, this different treatment of demand side and supply side resources can lead to significant economic inefficiencies and increased ratepayer cost if the full economic potential of efficiency measures is not considered. Energy efficiency that may be economic when compared with alternative supply resources can be left untapped.

This analysis models energy efficiency measures in a similar way to supply resources with a first year cost and subsequent years of energy savings based on a specific end use load shape. Both utilities provided information on the set of measures that are available within their systems together with their cost, lifetime, hourly load shape, and annual market potentials. Strategen modeled each of these measures independently and included them as a resource option in the capacity expansion modeling exercise. From the first explorative runs, it became apparent that the majority of those measures are economic compared to their supply side counterparts and the efficiency level of the Optimal Resource Portfolio primarily depends on the measures' potential, i.e., what energy efficiency level is available for the model to include in the portfolio. For modeling purposes, we allowed the full economic potential energy efficiency measures to be selected.[12]

The measures modeled are representative of the broader set of measures in TEP's and APS's energy efficiency program portfolio and include both residential and commercial sector programs, and end uses such as lighting, HVAC, hot water heating, industrial motors, refrigeration, and so on. The graphs below show the variety of measures that are available for TEP with a similar portfolio being available for APS.

[12] Economic potentials are determined by the utilities based on the evaluation method historically used by the ACC. Strategen believes this method to be a conservative approach that may not fully represent the full economic potential available. Additionally, the Energy Rules redefine energy efficiency cost effectiveness to mean "prudency." Thus the ACC's historic method of determining cost effectiveness would no longer be the practice going forward should the Energy Rules be finalized and implemented.

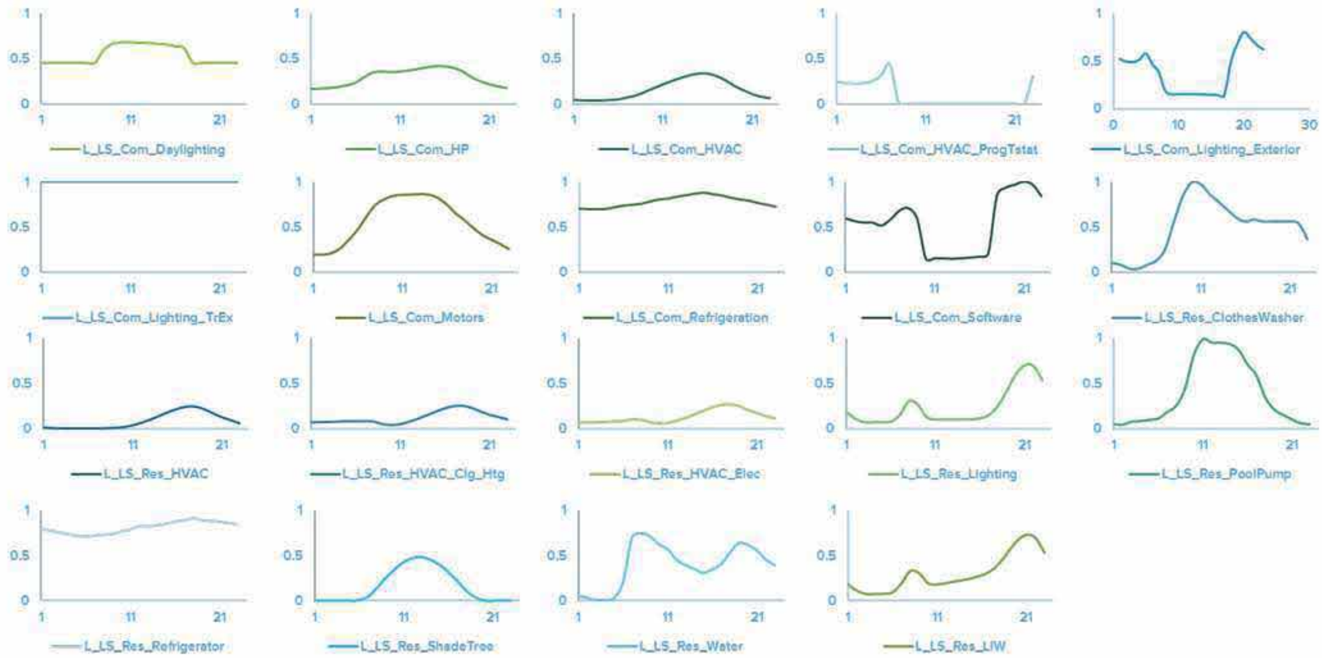


*Figure 10: Hourly profile of TEP EE measures (average over year)*

Based on our analysis, we believe that TEP and APS may be underestimating the potential savings per year that could be achieved through energy efficiency. In the first ten years of their energy efficiency program implementation, TEP and APS have succeeded in achieving cumulative savings close to 22%, at costs that were lower than originally predicted. Given their past performance, and the technological and cost advancements in energy efficiency, the level of increase in efficiency planned by the utilities appears overly conservative and thus limits the potential for energy efficiency's to reduce costs and emissions for Arizonians.

It is worth noting that the optimal portfolio of energy efficiency measures as selected in EnCompass is characterized by a different hourly profile, especially during summer months and during hours when Arizona load is usually at its peak. Thus, in addition to the energy savings, energy efficiency can deliver significant capacity benefits by reducing load during peak hours. For example, the graphs below show how the optimal energy efficiency portfolio has a larger capacity contribution than initially assumed by TEP.

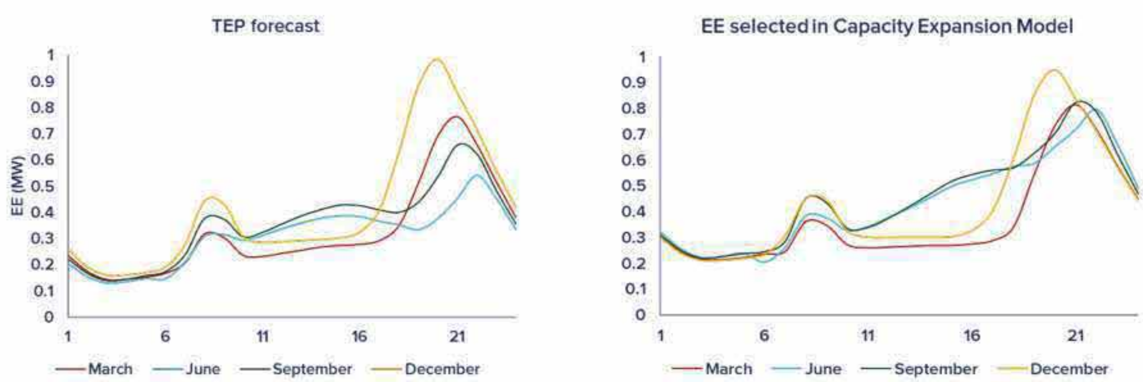


*Figure 11: TEP EE portfolio*

## 2.8. Firm Clean Energy Resources

The addition of new solar, and wind, in combination with maintaining the existing nuclear generation capacity at Palo Verde, can achieve a large majority of the 100% emissions reductions required under the Energy Rules by 2050. However, as the penetration of renewable resources increases – particularly in the 2030 to 2050 timeframe – it becomes more challenging to reach the 100% target at a low cost without some additional resource options that can provide firm, dispatchable clean energy. While these resources are not likely to be needed in the short term (i.e., before 2030), they should be considered over a longer planning horizon, or under a more aggressive emissions reduction target. Resources that fall into this category could include 1) much larger installations of battery storage that extend beyond the typical 4-6 hour timeframe, 2) geothermal, for which there are high quality resources available nearby in Nevada and Southern California, and 3) combustion turbines that burn "green hydrogen" fuel produced from a renewable energy source. While green hydrogen has yet to be commercialized, it is being actively considered by APS. This report is agnostic about which, if any, of these "firm clean" resources is more likely to be deployed in Arizona, however we do include a placeholder resource option in our analysis that could represent this. The assumptions for the "firm clean" placeholder resource were developed with the third of the above options in mind. As a rough approximation of the cost of a combustion turbine burning green hydrogen, we increased the capital cost of a standard combustion turbine by $1800/kW to account for the additional cost of the electrolyzer required to produce hydrogen fuel, as well as the cost of onsite tank storage facility to store the hydrogen fuel.[13] This assumes that hydrogen is produced and consumed on-site, with no need for additional transportation or underground storage, and also that it requires no additional pollution controls for NOx emissions, which would further increase the cost. Furthermore, we also assumed the cost of an incremental renewable resource that would be needed to power the electrolyzer with no emissions. We estimate that these additional costs would place the green hydrogen resource in a similar cost range to a geothermal resource which could be another option for the firm clean energy resource. The addition of firm clean energy resources was not selected by the model in the Optimal Resource Portfolio, however it was selected in the High Emissions Reduction Portfolio beginning around 2030.

## 2.9. Other Adjustments

Strategen incorporated other adjustments to the model inputs provided by the utilities that it deemed to be reasonable. For example, the capital costs of paired solar plus storage resources was adjusted down to reflect the fact that DC-coupled solar + storage systems share common power conversion equipment and interconnection costs that would not need

[13] Cost estimates were developed based upon projections from Sandia National Labs: https://prod-ng.sandia.gov/techlib-noauth/access-control.cgi/2011/114845.pdf

to be duplicated. Furthermore, future wind capital costs were adjusted to be more consistent with other forecasts from the U.S. Department of Energy National Renewable Energy Laboratory (NREL) and other industry sources. However, wind additions from New Mexico were limited to 200 MW per year for APS and 150 MW per year for TEP, to reflect limited transmission capacity in the region and to ensure a reasonable development timeline. Finally, market purchases and transfers between load regions were limited to reflect both transmission limits and recently tightening supply conditions in the region.

## 2.10. Transmission

Consistent with Arizona utilities' planning practices, new transmission lines were not endogenously modeled. This is a limitation that should be further explored due to the likely need for additional transmission to support renewable energy throughout the state of Arizona and imports from neighboring states. As APS and TEP's coal plants retire, particularly those in Eastern Arizona and New Mexico (e.g., Four Corners, Springerville, and San Juan), some transmission capability could potentially be repurposed to support wind imports. However, this may still be insufficient or new lines may be needed. To represent this, Strategen considered the impact of a $15/MWh transmission wheeling charge on all new wind imports. The estimated incremental cost of this would range from about $10-66 million per year (depending on how much wind is online), or about $434 million total in net present value terms. While this is a substantial additional cost, it is not significant enough to outweigh the $2 billion in savings from generation that were identified in Chapter 2 of this report.